TECHNICAL REVIEW DOCUMENT
For
RENEWAL of OPERATING PERMIT 96OPBO131

Public Service Company – Valmont Station
Boulder County
Source ID 0130001

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July 2007 and October 2008
Revised November 2008 and February, August and December 2009 and January 2010

I. Purpose:

This document will establish the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewed Operating Permit proposed for this site. The original Operating Permit was issued September 1, 2001. The expiration date for the permit was September 1, 2006. However, since a timely and complete renewal application was submitted, under Colorado Regulation No. 3, Part C, Section IV.C all of the terms and conditions of the existing permit shall not expire until the renewal Operating Permit is issued and any previously extended permit shield continues in full force and operation. This document is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the renewal application submitted July 5, 2005, comments on the draft permit and technical review document received on February 17, 2009, comments made from various individuals during the public comment period, comments received on January 15, 2010 from EPA during EPA's 45-day review period, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at http://www.cdphe.state.co.us/ap/Titlev.html. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this Operating Permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This Operating Permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this Operating Permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Source

This facility consists of one 199 MW coal/natural gas fired boiler and one 50 MW natural gas/No.2 fuel oil-fired combustion turbine. The boiler is equipped with low NO_X burners and over-fire air to reduce NO_X emissions. Emissions from this boiler pass through a bag-house to reduce particulate emissions. The boiler was equipped with a lime spray dryer to reduce SO_2 emissions. The lime spray dryer became operational in August 2002. In addition, Valmont station has a natural gas fired auxiliary boiler to provide heat for the facility when the main boiler is not functioning. Other emission sources at Valmont include fugitive emissions from coal handling and storage, ash handling and disposal and from traffic on paved/unpaved roads. An ash blower system, two (2) recycle ash silos, two (2) recycle ash mixers, two (2) lime storage silos and two (2) ball mill slakers were added to the facility to support the lime spray dryer. These additional emission units became operational in August 2002. Finally, Valmont station has a cold cleaner solvent vat and point source emissions above APEN significance levels from the ash silo and the coal handling system (crusher and conveyors). In addition, Public Service Company (PSCo) entered into a Voluntary Emissions Reduction Agreement with the Division. The provisions of that agreement became effective on January 1, 2003 and the appropriate provisions of that agreement have been included in this permit.

The PSCo's Valmont Generating Station is co-located with SWG Colorado's Valmont Combustion Turbine Facility. Since the two facilities are located on contiguous and adjacent property, belong to the same industrial grouping (first two digits of the SIC code are the same) and are under common control (SWG Colorado via a power purchase agreement with PSCo), they are considered a single stationary source for purposes of major stationary source new source review and Title V operating permit applicability. A separate Title V operating permit was issued for SWG Colorado's Valmont Combustion Turbine Facility (01OPBO238).

The facility is located in Boulder at 1800 N. 63rd Street in Boulder county. The Denver metro area, including Boulder, is classified as attainment/maintenance for particulate matter less than 10 microns (PM_{10}) and carbon monoxide (CO). Under that classification, all SIP-approved requirements for PM_{10} and CO will continue to apply in order to prevent backsliding under the provisions of Section 110(l) of the Federal Clean Air Act. The Denver metro area, including Boulder is classified as non-attainment for ozone and is part of the 8-hr Ozone Control Area as defined in Colorado Regulation No. 7, Section II.A.1.

There are no affected states within 50 miles of the plant. Rocky Mountain National Park and Eagles Nest and Rawah National Wilderness Areas, all Federal Class I designated areas, are within 100 kilometers of the plant.

The summary of emissions that was presented in the Technical Review Document (TRD) for the original permit issuance has been modified to more appropriately identify the **potential to emit (PTE)** of both criteria and hazardous air pollutants. Emissions (in tons/yr) at the facility are as follows:

Emission Unit	PM	PM_{10}	SO_2	NO_X	CO	VOC	Pb[1]	HAPS
PSCo – Valmont Station (96OPBO131)								
Main Boiler (Unit 5)	808.11	743.46	8,889.21	3,232.44	190.14	43.57	0.15	See Page 27
Turbine	249.66	249.66	1,997.28	2,197.28	204.72	5.24		
Auxiliary Boiler	0.2	0.2	0.06	10.74	9.02	0.59		
Ash Handling (point source - Silo)	5.4	5.4						
Ash Handling (fugitive)	26.96	9.68						
Coal Handling (point source – conveying and crusher)	0.53	0.19						
Coal Handling (fugitive)	12.54	4.42						
Recycle Ash Silos	0.055	0.055						
Recycle Ash Mixers	0.25	0.25						
Lime Storage Silos	0.0046	0.0046						
Ball Mill Slakers	0.25	0.25						
Ash Blower	1.05	1.05						
Haul Roads (fugitive)	36.84	7.71						
Total PSCo Emissions	**1,141.85**	**1,022.33**	**10,886.55**	**5,440.18**	**403.88**	**49.40**	**0.15**	**110.27 [16.44]**
SWG Colorado LLC – Valmont combustion Turbines (01OPBO238)								
Turbines and heaters	4.0	4.0	0.3	39	90.8	6.7		See Page 27
Total SWG Emissions	**4.0**	**4.0**	**0.3**	**39**	**90.8**	**6.7**		**3.00**
Total FACILITY Emissions	**2,361.70**	**1,443.21**	**10,886.85**	**5,479.18**	**494.68**	**56.10**	**0.5**	**113.27 [19.44]**

Emissions in brackets represent controlled HAP emissions. The lime spray dryer controls HF and HCl emissions.
[1]Lead (Pb) emissions are based on emission factors from AP-42, Section 1.1 (dated 9/98), Table 1.1-17.

Potential to emit used in the above table are based on the following information:

Criteria Pollutants

Potential to emit for the ash blower, ash silo, ball mill slakers, lime storage silos, recycle ash storage silos, recycle mixers and coal handling system (point source – conveying and crusher) are based on permitted emissions.

Potential to emit for NO_X, SO_2 and PM from the main boiler are based on emission limitations included in the permit (Reg 1 for SO_2 and PM (1.1 lb/mmBtu and 0.1 lb/mmBtu, respectively) and Acid Rain limits for NO_X (0.40 lb/mmBtu)), the design heat input rate and 8760 hours per year of operation. PM_{10} emissions from the main boilers are presumed to be 92% of PM emissions (per AP-42, Section 1.1 (dated 9/98), Table 1.1-6). VOC and CO emissions from the main boilers are based on emissions from the worst case fuel. Emissions from VOC and CO were estimated using AP-42 emission factors (Section 1.1, dated 9/98, Tables 1.1-3 and 1.1-19 for coal and Section 1.4, dated 3/98, Tables 1.4-1 and 1.4-2 for natural gas) and the maximum fuel consumption rate. The maximum coal consumption rate is based on the design heat input rate, the heat content of the coal from the APEN submitted on April 30, 2008 and 8760 hours per year of operation. The maximum natural gas consumption rate is based on the design heat input rate, a natural gas heat content of 1020 Btu/scf (per AP-42) and 8760 hours per year of operation.

Potential to emit for PM and SO_2 from the turbine are based on emission limitations included in the permit (Reg 1 for SO_2 and PM (0.8 lbs/mmBtu and 0.1 lb/mmBtu, respectively)), the design heat input rate and 8760 hours per year of operation. PM_{10} emissions are presumed to equal PM. NO_X, CO and VOC emissions from the turbine are based on emissions from the worst case fuel, using AP-42 emission factors (Section 3.1, dated 4/00, Tables 3.1-1 and 3.1-2a), the design heat input rate and 8760 hours per year of operation.

Potential to emit from the auxiliary boiler is based on AP-42 emission factors (Section 1.4, dated 3/98, Tables 1.4-1 and 1.4-2) and the maximum fuel consumption rate. Note that the maximum fuel consumption rate is based on the design heat input rate, an assumed natural gas heat content of 1020 Btu/scf and 8760 hours per year of operation. It should be noted that although this boiler is subject to a Reg 1 PM limitation, that limit has not been used to estimate the potential to emit of PM. Since this unit burns a clean fuel and runs infrequently, the Division considers that using the Reg 1 PM limit to estimate potential to emit is not appropriate for this unit.

Potential to emit from fugitive emissions from haul roads, coal handling and ash handling are based on the estimates provided with the source's comments on the draft permit, which were submitted on February 17, 2009.

Potential to emit from the SWG Colorado Valmont Combustion Turbine Facility are based on permitted emissions. The emission limitations in the permit are facility wide limits.

Hazardous Air Pollutants (HAP)

The potential to emit table on page 3 provides total HAPs for each operating permit. The breakdown of HAP emissions (both controlled and uncontrolled) by individual HAP and emission unit is provided on page 27 of this document. HAP emissions (both controlled and uncontrolled) as shown in the table on page 27, are based on the following information:

Potential to emit of HAPS were only determined for the main boiler, the auxiliary boiler and the turbine. HAPS were not estimated for the other emission units as HAPs were presumed to be negligible from these sources.

HAP emissions from the auxiliary boiler are based on AP-42 emission factors (Section 1.4, dated 3/98, Tables 1.4-3 and 1.4-4) and the maximum fuel consumption rate. Emissions of hexane are based on an EPRI emission factor (from an EPRI paper, dated May 2000) and the maximum natural gas consumption rate.

HAPS from the turbine are based on worst case emissions, which are based on AP-42 emission factors (Section 3.1, dated 4/00, Tables 3.1-3, 3.1-4 and 3.1-5), the design heat input rate and 8760 hours per year of operation.

Metal HAP emissions from the main boiler are based on AP-42 emission factors (Section 1.1, dated 9/98, Table 1.1-18) and the maximum coal consumption rate. Mercury emissions from the main boiler are based on a January 22, 2008 performance test. Controlled HF and HCl emissions from the main boiler are based on the maximum emission factor, in units of lbs/ton, determined from reported HF and HCl emissions and coal consumption on several current APENS (2004 – 2007 data) and the maximum coal consumption rate. Uncontrolled HF and HCl emissions from the main boiler are based on the emission factors used to on several APENS (1997 – 2002 data) that were submitted prior to installing the lime spray dryer on the unit. Emissions of benzene, formaldehyde and toluene are based on AP-42 emission factors (Section 1.4, dated 3/98, Table 1.4-3) and the maximum natural gas consumption rate. Emissions of hexane are based on an EPRI emission factor (from an EPRI paper, dated May 2000) and the maximum natural gas consumption rate.

HAP emissions from SWG Valmont turbines and heaters are based on AP-42 emission factors, design rate and 8760 hours per year of operation since there are no fuel consumption limits specified in the SWG Valmont permit.

Note that actual emissions are typically less than potential emissions and actual emissions from the PSCo sources are shown on page 28 of this document.

Compliance Assurance Monitoring (CAM) Requirements

The source addressed the applicability of the CAM requirements in their renewal application and is discussed further in the document under Section III – Discussion of Modifications Made, under “Source Requested Modifications”.

MACT Requirements

Case-by-Case MACT - 112(j) (40 CFR Part 63 Subpart B §§ 63.50 thru 63.56)

Under the federal Clean Air Act (the Act), EPA is charged with promulgating maximum achievable control technology (MACT) standards for major sources of hazardous air pollutants (HAPs) in various source categories by certain dates. Section 112(j) of the Act requires that permitting authorities develop a case-by-case MACT for any major sources of HAPs in source categories for which EPA failed to promulgate a MACT standard by May 15, 2002. These provisions are commonly referred to as the “MACT hammer”.

Owners or operators that could reasonably determine that they are a major source of HAPs which includes one or more stationary sources included in the source category or subcategory for which the EPA failed to promulgate a MACT standard by the section 112(j) deadline were required to submit a Part 1 application to revise the operating permit by May 15, 2002. The source submitted a notification indicating that Valmont Station was a major source for HAPS, with equipment under the source category for industrial, commercial and institutional boilers and process heaters and combustion turbines.

It should be noted that although controlled emissions from the facility are below the major source level (10 tons/yr of any individual HAP and 25 tons/yr of combined HAPS), since the permit does not require that the control device (lime spray dryer to reduce HF and HCl emission) be used at all times and there are no HAP limits in the permit, the Division considers that the facility is a major source for HAPS.

Since the EPA has signed off on final rules for all of the source categories which were not promulgated by the deadline, the case-by-case MACT provisions in 112(j) no longer apply. Note that there is a possible exception to this, as discussed later in this document (see under industrial, commercial and institutional boiler and process heaters).

RICE MACT (40 CFR Part 63 Subpart ZZZZ)

The RICE MACT (40 CFR Part 63 Subpart ZZZZ) was signed as final on February 26, 2004 and was published in the Federal Register on June 15, 2004. An affected source under the RICE MACT is any existing, new or reconstructed stationary RICE with a site-rating of more than 500 hp and located at a major source for HAPS; however, only existing (commenced construction or reconstruction prior to December 19, 2002) 4-stroke rich burn (4SRB) engines with a site-rating of more than 500 hp were subject to requirements. There are two diesel fired engines included in the insignificant activity list. One of these, an emergency generator is greater than 500 hp and the other (drives a water pump) is less than 500 hp. Since the emergency generator is an existing compression ignition engine, it does not have to meet the requirements of Subparts A and ZZZZ, including the initial notification requirements as specified in 40 CFR Part 63 Subpart ZZZZ § 63.6590(b)(3).

In addition, revisions were made to the RICE MACT to address engines $\leq$ 500 hp at major sources and all size engines at area sources. These revisions were published in the Federal Register on January 18, 2008. Under these revisions, existing compression ignition (CI) engines, 2-stroke lean burn (2SLB) and 4-stroke lean burn (4SLB) engines were not subject to any requirements in either Subparts A or ZZZZ (40 CFR Part 63 Subpart ZZZZ § 63.6590(b)(3)). For purposes of the MACT, for engines $\leq$ 500 hp, located at a major source, existing means commenced construction or reconstruction before June 12, 2006. The water pump engine included in the insignificant activity list is considered existing and therefore is not subject to the MACT. Although the renewal application indicated that a new engine (< 500 hp) had been installed at this facility, since this engine was installed prior to June 12, 2006 it is also not subject to the MACT.

Combustion Turbine MACT (40 CFR Part 63 Subpart YYYY)

In accordance with 40 CFR Part 63 Subpart YYYY §63.6090(b)(4), existing (construction commenced prior to January 14, 2003) stationary combustion turbines do not have to meet the requirements of Subparts A and YYYY, including the initial notification requirements.

Industrial, Commercial and Institutional Boilers and Process Heaters MACT (40 CFR Part 63 Subpart DDDDD)

The final rule for industrial, commercial and institutional boilers and process heaters was signed on February 26, 2004 and was published in the Federal Register on September 13, 2004. There are propane portable heaters and miscellaneous heaters included in the insignificant activity list in Appendix A of the permit. However, these units do not meet the definition of boiler or process heater specified in the rule (the definition of process heater excludes units used for comfort or space heat). Therefore the heaters included in the insignificant activity list would not be subject to the Boiler MACT requirements.

The auxiliary boiler, which is included in Section II of the permit, burns natural gas as fuel. Since the unit is a large existing gaseous fuel unit it is only subject to the initial notification requirements as specified in 40 CFR Part 63 Subpart DDDDD § 63.7506(b)(2). The initial notification was submitted on February 16, 2005, prior to the March 12, 2005 deadline.

As of July 30, 2007, the Boiler MACT was vacated; therefore, the provisions in 40 CFR Part 63 Subpart DDDDD are no longer in effect and enforceable. The vacatur of the

Boiler MACT triggers the case-by-case MACT requirements in 112(j), referred to as the MACT hammer, since EPA failed to promulgate requirements for the industrial, commercial and institutional boilers and process heaters by the deadline. Under the 112(j) requirements (codified in 40 CFR Part 63 Subpart B §§ 63.50 through 63.56) sources are required to submit a 112(j) application by the specified deadline. As of this date, EPA has not set a deadline for submittal of 112(j) applications to address the vacatur of the Boiler MACT. Although this unit was only subject to initial notification requirements, the Division considers that a 112(j) application should be submitted for this unit. Therefore, the Division will include a requirement to submit a 112(j) application in the permit by the deadline set by the Division and/or EPA.

Gasoline Distribution MACTs

A 500 gallon aboveground gasoline tank is included in the insignificant activity list (listed as an insignificant activity because emissions are less than the APEN de minimis level per Reg 3, Part C, Section II.E.3.a). There are potential MACT standards that could apply to this operation: Gasoline Distribution (Stage I) – 40 CFR Part 63 Subpart R (final rule published in the federal register on December 14, 1994), Gasoline Dispensing Facilities – 40 CFR Part 63 Subpart CCCCCC (final rule published in the federal register on January 10, 2008) and Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities – 40 CFR Part 63 Subpart BBBBBB (final rule published in the Federal Register on January 10, 2008). Both of the rules published on January 10, 2008 only apply at area sources. Since this facility is a major source for HAPS, the requirements in those rules do not apply to the gasoline tank at this facility. The Gasoline Distribution (Stage I) MACT applies to bulk gasoline terminals and pipeline break-out stations. The gasoline dispensing equipment at this facility does not meet the definition of a bulk gasoline terminal or a pipeline break-out station. Therefore, none of the MACT requirements associated with gasoline distribution apply to the equipment at this facility.

Note that since this tank is less than 550 gallons it is not subject to the Requirements in Colorado Regulation No. 7, Section VI.B.3.b.

Federal Clean Air Mercury Rule Requirements

The EPA published final rules to address mercury emissions from coal-fired electric steam generating units on March 15, 2005. These rules are referred to as the Clean Air Mercury Rule (CAMR), which required mercury standards for new and modified emission units and provided a trading program for existing units. Under this program, sources would be required to get a permit (application due date July 10, 2008) and to meet monitoring system requirements (install and conduct certification testing) by January 1, 2009.

However, on February 8, 2008 a DC Circuit Court vacated the CAMR regulations for both new and existing units. Therefore, the federal CAMR requirements are not in effect, as of the issuance of this renewal permit.

State Clean Air Mercury Rule Requirements

Although the Division did adopt provisions from the federal CAMR rule into our Colorado Regulation No. 6, Part A, the Division also adopted State-only mercury requirements in Colorado Regulation No. 6, Part B, Section VIII. As discussed above the provisions from the federal CAMR rule have been vacated and are no longer applicable. While the state-only mercury requirements rely in some part of the federal CAMR rule (primarily for monitoring and reporting requirements), there are emission limitations and permit requirements that do not rely on the federal rule and are still in effect.

To that end, as an existing mercury budget unit the main boiler is required to comply with either of the following standards on a 12-month rolling average basis beginning January 1, 2014 (Colorado Regulation No. 6, Part B, Section VIII.C.1.b):

0.0174 lb/GWh OR 80 percent capture of inlet mercury

The main boiler would be subject to more stringent mercury standards beginning January 1, 2018 as set forth in Colorado Regulation No. 6, Part B, Section VIII.C.1.c.

It should be noted that if the main boiler qualifies as a low emitter (actual mercury emissions of no more than 29 lbs/yr), the mercury standards indicated above do not apply.

Since the mercury limitations do not apply until 2014 and the permit application is not due until 18 months prior to commencing construction on the mercury control equipment (Colorado Regulation No. 6, Part B, Section VIII.D.2) the renewal permit does not include the state-only mercury requirements.

Regional Haze Requirements

The main boiler (Unit 5) at this facility is subject to the regional haze requirements for best available retrofit technology (BART) and as such a BART analysis was conducted and a permit has been issued to address the BART requirements. The BART requirements have been included in Colorado Construction Permit 07BO0110B, which was issued September 12, 2008.

Although emission limitations for PM, SO_2 (annual limitations) and NO_X are included in the BART permit, only the PM and NO_X emission limitations are new. The SO_2 limitations that were included in the BART permit are the same limitations included in the current Title V permit, which were based on the Voluntary Emissions Reduction Agreement.

The BART permit specifies that PSCo shall demonstrate compliance with the PM and NO_X unit-specific emission limits as expeditiously as practicable, but in no event later than five years following EPA approval of the state implementation plan for regional haze that incorporates these BART requirements, whichever is earlier. Although the PM and NO_X requirements in the BART permit do not take effect until EPA approves the Regional Haze SIP and the BART permit does not require that a Title V permit application to incorporate the BART provisions be submitted until 12 months after startup of the modified NO_X control equipment, the provisions in the BART permit have been included in the renewal permit.

III. Discussion of Modifications Made

Source Requested Modifications

The source requested the following changes in their July 5, 2005 renewal application.

Cold Cleaner Solvent Vat - Section I, Conditions 1.1 and 6.1, Section II, Condition 11 and Appendices B and C

The source indicated that the Safety-Kleen Cold Cleaner Solvent Vats have been retired and removed from the facility. The Safety-Kleen System has been replaced with a System One Parts Washer, which contains the solvent within the system and does not generate any waste. Therefore, they have requested that references to the Safety-Kleen solvent vats be removed from the permit. The Division has replaced the references to "safety-kleen" with "system one".

Section I, Condition 5 (Compliance Assurance Monitoring (CAM))

The source indicated that this condition needed to be revised to address the CAM requirements for this facility. The CAM requirements apply to any emission unit that uses a control device to meet an emission limitation or standard and has pre-controlled emissions above the major source level. There are several emission points at the facility that could potentially be subject to the CAM requirements. The source provided information regarding the applicability of the CAM requirements to the emission units at the facility as discussed below.

Emission sources with no emission limitations

The source identified the following activities as units with no emission limitations and therefore not subject to the CAM requirements: the cold cleaner solvent vat and fugitive emissions from coal handling and storage, ash handling and traffic on paved and unpaved roads. Although the grandfathered coal crusher does not have any emission limitations, this unit has been removed and replaced by the new crusher, which is addressed below.

Emission sources with emission limitations

No control device

The combustion turbine is subject to Reg 1 SO_2 and PM emission limitations and the auxiliary boiler is subject to a Reg 1 PM limitation. However, neither unit is equipped with a control device, therefore, the CAM requirements do not apply to either of these units.

Although not specifically identified as an uncontrolled emission unit in the source's renewal application, the Division considers that the ash blower vent is uncontrolled. As indicated in the technical review document that was prepared to include the Voluntary Emissions Reduction Agreement requirements for the Metro units (revised permit issued August 25, 2003), air from the blower is filtered before being exhausted. Since the blower cannot be operated without the filter system, the filter system is not considered a control device, because it is integral to the operation of the unit. Since the ash blower is not equipped with a control device, it is not subject to CAM.

Pre-control emissions below the major source level

The following emission units have pre-control emissions below the major source level and therefore are not subject to CAM.

<u>Ash silo, lime silos and recycle ash silos:</u> PM and PM_{10} emissions were calculated for these emissions units using the uncontrolled emission factors specified in the permit and the permitted throughput rate and emissions were below the major source level for each activity. Note that for the ash silo total emissions from silo loading and both unloading options (open and enclosed truck) were below the major source level.

<u>Recycle ash mixers and ball mill slakers:</u> Permitted emissions from these emission units are based on grain loading specifications from the manufacturer and design rate for the blowers. Therefore estimating uncontrolled emissions are difficult. Based on the permitted emission rate, the associated control devices would have to have a control efficiency of greater than 99.7% in order to have uncontrolled emissions below the significance level. For the mixers and slakers, the Division has considered that for similar emission units that the control efficiency is about 95%. Therefore, the Division considers that uncontrolled emissions from these units are below the major source level.

<u>Coal handling (conveying and crusher):</u> Permitted emissions from coal handling are based on emission factors for conveying that rely on wind speed and the calculations were performed using a low wind speed (1 mph) to simulate that the conveyors are covered. Permitted emissions from the crusher took credit for the enclosure as a control method (an efficiency of 95% was assumed). The Division calculated uncontrolled emissions from coal conveying and crusher using uncontrolled emission factors (for the conveyors, a higher wind speed (8.7 mph) was used to simulate no control) and the permitted coal throughput rate and emissions were below the major source level.

Pre-control emissions above the major source level

The source identified the main boiler (Unit 5) as being subject to CAM, since a control device is required to meet the PM emission limitations. Unit 5 is subject to PM, SO_2 and NO_X emission limitations. Controlled emissions of these pollutants exceed the major source level and this unit uses emission controls (baghouse for PM, lime spray dryer for SO_2 and low NO_X burners and over-fire air for NO_X) to meet its emission limitations. Therefore, Unit 5 is potentially subject to the CAM requirements.

Unit 5 is subject to SO_2 and NO_X emission limitations under the Acid Rain Program (Section III of the current permit). Pursuant to 40 CFR Part 64 § 64.2(b)(1)(iii), the CAM requirements do not apply to Acid Rain Program emission limitations.

Unit 5 is subject to a short-term SO_2 emission limitation (3-hr rolling average), an annual SO_2 emission limitation for the Metro units (per a voluntary emissions reduction agreement) and a 30-day NO_X limitation. The current Title V permit requires that the source use continuous emission monitoring systems to demonstrate compliance with the SO_2 and NO_X emission limitations. Therefore, since the Title V permit specifies a continuous compliance method for these emission limitations, the CAM requirements do not apply in accordance with the provisions in 40 CFR Part 64 § 64.2(b)(1)(iv).

CAM does apply to the Unit 5 with respect to the PM emission limitations. Note that although the unit is subject to opacity limits, they are not emission limitations subject to CAM requirements. The source submitted a CAM plan with their renewal application. In their CAM plan, the source proposed visible emissions, pressure differential and preventative maintenance as indicators. For visible emissions, excursions are identified as an opacity value exceeding 15% for one minute or more and any long term increase in opacity of 10% above baseline levels for normal operation. For pressure differential, an excursion is defined as an increase in differential pressure of 3 inches of water column or greater from normal baseline levels accompanied by a sustained increase in opacity over 10%.

The Division has reviewed the CAM plan submitted and while we accept the plan in part, we consider that changes to the plan are necessary. The Division considers that the following changes are necessary to the plan.

Visible Emissions

The Division agrees that sudden spikes in opacity are a reasonable indicator that the baghouse operation may have been compromised. The 15% indicator level proposed by PSCo is below the opacity limitations set for Unit 5. Although PSCo has not correlated 15% to a level of PM emissions, this is a short term (one minute or more) indicator of baghouse performance and as specified in 40 CFR Part 64 § 64.4(c)(1), emission testing is not required to be conducted over the indicator range or range of potential emissions. Given that the PM standard is based on the average of three one (1) hour tests and past performance tests indicate that the PM emissions are less than

50% of the standard, the short term 15% opacity indicator serves to provide an indication of proper baghouse operation and as such can be reasonable indicator that Unit 5 is in compliance with the PM limitations.

The second indicator range of “a long term increase in opacity emissions from baseline conditions during normal operations to opacity emissions greater than 10% over an extended period of time” proposed by the source is non-specific as to the time frame (i.e., averaging time) and it is not clear that the 10% opacity represents an acceptable opacity level as an indicator range. Specifically PSCo did not correlate the 10% opacity to a PM emission level, nor did they submit any performance test data with their CAM plan.

Therefore, the Division will include as CAM, the compliance provisions required for new (constructed after February 28, 2005) electric utility steam generating units subject to PM fuel based emission limitations (i.e. units of lb/mmBtu) in 40 CFR Part 60 Subpart Da, since such monitoring represents presumptively acceptable monitoring in accordance with the provisions in 40 CFR Part 64 § 64.4(b)(1)(4). The compliance provisions specified in Subpart Da require that a baseline opacity level be set during a performance test and then requires monitoring of opacity emissions on a 24-hour average. If the opacity 24-hour average exceeds the baseline level, then the source must investigate and take the appropriate corrective action.

The baseline opacity level determined under the provisions of NSPS Subpart Da specify that 2.5% opacity be added to the average opacity determined during the performance test, although the baseline opacity level can be no lower than 5% opacity. Since the units required to conduct this monitoring under NSPS Subpart Da are subject to more stringent particulate matter limitations, the opacity add-on level will be higher (ranging from 2.5% to 5%) and will be based on the results of the performance test. However, in no case would the baseline opacity be set lower than 5%.

The Division intends to require that a performance test be conducted within 180 days of renewal permit issuance to demonstrate compliance with the PM emission limitation, therefore, the permit will require that PSCo set the baseline opacity during this test. Although a performance test was conducted on Unit 5 in 2001 and information on opacity emissions during this test may be available (PSCo is only required to retain monitoring data for five years after it is generated) and thus may be used to set the indicator range, the 2001 test was conducted prior to the installation of the lime spray dryer on Unit 5. Therefore, the Division considers that it is more appropriate to set the indicator range on a more recent and representative test. As indicated in 40 CFR Part 64 § 64.4(e)(2), if installation of equipment and/or performance testing to set indicator ranges is necessary prior to performing the monitoring under CAM, that the schedule for completing installation and/or testing and beginning operation of the monitoring shall be as expeditiously as practicable but no longer than 180 days after approval of the permit. To that end, the permit requires that the performance test be conducted, the proposed baseline opacity be submitted for Division approval and that monitoring 24-hour opacity averages commence within 180 days of renewal permit issuance. In addition, the permit will require the source to submit a minor modification application to revise the Title V permit and incorporate the proposed baseline opacity as the indicator range for the 24-hr average opacity. Such application shall be submitted with the proposed baseline opacity.

Pressure Differential

The source has indicated that an excursion would be "an increase in differential pressure across a baghouse of 3 inches of water column or greater from the unit's normal specific operating load during normal operating conditions, as well as a sustained increase in opacity greater than 10%". While the proposed language does not specifically define the pressure differential for the "unit's normal specific operating load", in their justification the source indicates that the normal pressure differential varies based on the operating load. While the Division understands that it may be difficult to identify specific ranges since the appropriate pressure differential varies depending on the load, failure to identify the specific range makes it difficult for the Division to independently determine whether an excursion has occurred. In addition, as indicated in the CAM plan, an increase or decrease in the pressure differential from the normal level at a specific operating load is not necessarily considered an indicator of decreased baghouse performance by itself. However, an increase or decrease in the pressure differential from the normal level, accompanied by a sustained increase in opacity is an indication of potential baghouse problems.

Since the normal pressure differential is specific to load and cannot be easily defined and because pressure differential by itself is not necessarily an indicator of potential problems with the baghouse, the Division will not include pressure differential in the CAM plan as an indicator. In accordance with 40 CFR Part 64 § 64.4(b)(4), presumptive CAM is monitoring included for standards that are exempt from CAM (i.e. NSPS standards promulgated after November 15, 1990) to the extent that such monitoring is applicable to the performance of the control device (and associated capture system). As discussed previously, the Division has revised the source's CAM plan to require that visible emissions be monitored in accordance with the monitoring required for new boilers subject to 40 CFR Part 60 Subpart Da. The emission limitations and monitoring for new boilers were published as final in the February 27, 2006 federal register, although changes to the monitoring requirements were published as final in the federal register on June 13, 2007. New boilers subject to the revised PM emissions limits in 40 CFR Part 60 Subpart Da are required to monitor compliance with the PM emission limitation using their COM by establishing a baseline opacity. Therefore, the baseline opacity monitoring that the Division is including in the CAM plan represents presumptive CAM and the Division does not believe that it is necessary to include pressure differential as an additional indicator.

It should be noted that new sources subject to the NSPS Da PM limitation are also required to conduct annual performance tests. While the Division has not included annual performance testing in the permit as part of the CAM plan, the Division does require performance tests as periodic monitoring to demonstrate compliance with the

PM limitations. Frequency of testing is annual, unless the results of the testing are much lower than the standard, then less frequent testing is allowed.

Preventative Maintenance

The preventative maintenance that the source has proposed is a monthly review of historic minute opacity data and that based on this review, if warranted, repairs will be initiated to internal and/or external baghouse components. It is not clear what specifically the source would be looking for in the historic minute opacity data and what would trigger any repairs. The Division considers that preventative maintenance is important to the proper operation of the baghouse, therefore, the Division has revised the preventative maintenance indicator to require semi-annual internal inspections of the baghouse. This indicator has been included in other CAM plans for other PSCo facilities.

In general, the CAM plan has been included in Appendix I of the permit as submitted, except that the corrections indicated above have been made to the plan and some language has been omitted, revised or relocated in order to streamline the plan.

Unit 5 burns coal as its primary fuel; however, the unit can operate on natural gas only as a back-up fuel. Although Unit 5 is equipped with a baghouse, when burning natural gas, Unit 5 would be able to meet the PM emission limitation without the baghouse. Therefore, when the unit burns only natural gas as fuel, CAM would not apply.

<u>Section II, Condition 4.3</u>

In their February 17, 2009 comments on the draft permit and technical review document, the source requested that emissions from the turbine be based on the lower heating value of the fuel, rather than the higher heating value. The source also requested that the emission factors be adjusted as they were for other PSCo permits, such as Ft. Lupton and Alamosa. The Division adjusted the AP-42 emission factors, which are based on the higher heating value of the fuel to a lower heating value basis. The factors were adjusted using the equation below and the average heat values that were provided for the PSCo Ft. Lupton first renewal permit (issued July 1, 2002) and are documented in the technical review document for the first renewal (higher heating value = 1016.5 Btu/SCF and lower heating value 916.5 Btu/SCF).

$$\text{EF lbs/mmBtu - LHV} = \frac{\text{EF lbs/mmBtu - HHV} \times \text{Btu gas, HHV}}{\text{Btu gas, LHV}}$$

<u>Section II, Condition 5.3</u>

In their February 17, 2009 comments on the draft permit, the source indicated that the reference to SO_2 in Condition 5.3 should be corrected to PM. The change was made as requested.

Grandfathered Coal Crusher – Section I, Condition 6.1, Section II, Conditions 10, 10.1, 10.3, 10.9 and 10.10 and Appendices B and C

The source indicated that the grandfathered coal crusher has been removed from service as part of the upgrades made to the coal handing system and requested that references to the grandfathered crusher be removed. The changes have been made as requested.

Note that the Division will also remove references to the new crusher and the upgraded coal handling system. Since the new crusher is the only crusher and the conveying system upgrades have been completed it isn't necessary to specifically note that the crusher is new and that the conveying system was upgraded.

Section II, Conditions 10.4,10.5, 10.6 and 10.7

The source indicated that the upgrades to the coal handling system have been completed and that the above conditions no longer apply and should be removed from the permit. The changes have been made as requested.

Section II, Condition 13.1

The source requested that the operation and maintenance requirements for the boiler be linked to the CAM plan and suggest that the language in Condition 13.1 be revised to reference the CAM plan.

The Division has added the CAM requirements as "new" conditions 1.13 and 20. The Division removed the language in Condition 13.1 regarding the COMS and opacity spikes. The Division considers that with the CAM plan requirements this language is no longer necessary.

Section II, Condition 18.1.4

The source indicated that the "startup period" of the voluntary agreement has passed and that this requirement should be removed from the permit. The change has been made as requested. In addition, the Division removed Condition 18.2.4, which also relates to the "startup period".

Insignificant Activity List – Appendix A

The source indicated the following changes to the insignificant activity list in Appendix A of the permit:

- A 500 gal diesel tank was added for the new diesel fire pump.

- A 375 hp diesel-fired internal combustion engine driving a fire pump was added to the facility. The engine is expected to operate less than 340 hrs per year.

- The two (2) 2.5 million gallon No. 2 fuel oil tanks have been removed from the site.

- The 825,000 gallon No. 2 fuel tank was scheduled to be removed in the summer of 2005.

The Division has made the revisions to the insignificant activity list as requested.

In their comments on the draft permit (submitted on February 17, 2009), the source requested the following changes to the insignificant activity list.

- The water pump engine was removed from the list, since it has been removed from the facility.

- Remove the category for crude and/or condensate storage tanks < 40 gallons (Reg 3, Part C, Section II.E.3.ddd) and the miscellaneous crude oil or condensate storage tanks listed under the category. The condensate tanks at this facility do not meet the definition of condensate tanks for which this exemption applies and there are no crude oil storage tanks at this facility. Note that the condensate tanks are listed as “not sources of emissions”.

- The portable heaters at the facility are all diesel fuel-fired, therefore, the categories for fuel burning equipment < 5 and 10 mmBtu/hr have been removed. Diesel fuel-fired portable heaters are listed under the category for units with emissions below the APEN de minimis level (Reg 3, Part C, Section II.E.3.a).

<u>Other Modifications</u>

In addition to the modifications requested by the source, the Division has included changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this renewal.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments, to the Valmont Station Operating Permit with the source’s requested modifications. These changes are as follows:

<u>General</u>

- The Reg 3 citations were revised throughout the permit, as necessary, based on the recent revisions made to Reg 3.

<u>Page Following Cover Page</u>

- Monitoring and compliance periods and report and certification due dates are shown as examples. The appropriate monitoring and compliance periods and report and certification due dates will be filled in after permit issuance and will be based on permit issuance date. Note that the source may request to keep the same monitoring and compliance periods and report and certification due dates as were provided in the original permit. However, it should be noted that with this option, depending on the permit issuance date, the first monitoring period and compliance period may be short (i.e. less than 6 months and less than 1 year).

- Changed the responsible official.

Section I - General Activities and Summary

- Revised Condition 1.1 to indicate that the definition of the 8-hour ozone control area is in Regulation No. 7 and to address the attainment status of the area in which the facility is located.

- Revised Condition 1.1 to indicate that the SWG Colorado Valmont Combustion Turbine Facility is co-located and that the two facilities (SWG and PSCo) are considered a single source.

- In Condition 1.4, the phrase "last paragraph" was added after Section V, condition 3.g to indicate which part is state-only enforceable. In addition, Section V, condition 3.d was added as a state only condition in Condition 1.4. Note that Section V, Condition 3.d (affirmative defense provisions for excess emissions during malfunctions) is state-only until approved by EPA in the SIP.

- Made minor revisions to the language in Condition 3 (prevention of significant deterioration) to be more consistent with other permits. In addition, revised this condition to address the attainment status of the area in which the facility is located.

- Added a column to the Table in Condition 6.1 for the startup date of the equipment. In addition, "Unit 5" was added to the description of the main boiler to more clearly identify that unit. Also, the P002 identifier was applied to the coal handling system. Although this identifier was previously used for the grandfathered crusher, the identifier P003 had been used twice (for the upgraded coal handling system and the recycle ash silos).

Section II.1 – Main Boiler (Unit 5), Coal Firing

- Added "Unit 5" to the table header to more clearly identify the unit.

- References to fuel usage or fuel sampling were replaced with coal usage or coal sampling.

- Revised the language in Condition 1.4.2 to specify that the performance tests shall be used to set the baseline opacity for the CAM plan and specified how the baseline opacity shall be determined.

- Revised the table column “Monitoring – Interval” for Condition 1.12 by replacing “quarterly” with “annually”.

- Removed the last sentence from Condition 1.12. This condition already refers the reader to Section III for Acid Rain provisions and this last sentence is not necessary.

<u>Section II.2 – Main Boiler (Unit 5), Natural Gas Firing</u>

- Added “Unit 5” to the table header to more clearly identify the unit.

- Based on EPA’s response to a petition on another Title V operating permit, minor language changes were made to various permit conditions (both in the table and the text) to clarify that only natural gas is used as fuel for permit conditions that rely on fuel restriction for the compliance demonstration.

- Revised the table column “Monitoring – Interval” for Condition 2.10 by replacing “quarterly” with “annually”.

- Removed the last sentence from Condition 2.10. This condition already refers the reader to Section III for Acid Rain provisions and this last sentence is not necessary.

<u>Section II.3 – Main Boiler (Unit 5) , Combination Fired</u>

- Added “Unit 5” to the table header to more clearly identify the unit.

<u>Sections II.4 and 5 – Turbine</u>

- Based on EPA’s response to a petition on another Title V operating permit, minor language changes were made to various permit conditions (both in the table and the text) to clarify that only natural gas and/or No. 2 fuel oil are used as fuel for permit conditions that rely on fuel restriction for the compliance demonstration.

- The SO_2 emission factor was replaced with the default value of 3.4×10^{-3} lb/mmBtu (noted in footnote h in AP-42, Section 3.1, Table 3.1-2a). The Division considers that it is not necessary to determine the sulfur content of the natural gas in order to calculate annual emissions. In addition the notes at the bottom of the table for Section II.4 were removed since they relate to the sulfur component of the emission factor.

- The sentence “No. 2 fuel oil shall be used as fuel to monitor compliance with the particulate matter limitation” was replaced with “In the absence of evidence to the contrary, compliance with the SO_2 limitation is presumed whenever No. 2 fuel oil is burned as fuel” in Condition 5.3.

- The phrase “superseding the less stringent two (2) year period specified in Regulation No. 1, Section VIII.C” was removed from Condition 5.6. The two year recordkeeping requirements will be included in the permit shield for streamlined conditions (Section IV.3).

- Added “credible” before “evidence” in Conditions 5.3 and 5.4.

<u>Section II.6 – Auxiliary Boiler</u>

- Added “Auxiliary” to the table header to more clearly identify the unit.
- Removed the footnote at the bottom of the table, since FI is not used in the table.
- Based on EPA’s response to a petition on another Title V operating permit, minor language changes were made to various permit conditions (both in the table and the text) to clarify that only natural gas is used as fuel for permit conditions that rely on fuel restriction for the compliance demonstration.
- Added a requirement to submit a case-by-case MACT analysis.

<u>Section II.8 – Fugitive Particulate Emissions</u>

- Based on comments received during the public comment period, the following phrase was added to Condition 8.2.1 “[t]he 20% opacity, no off-property transport, and nuisance emission limitations are guidelines and not enforceable standards and no person shall be cited for violation thereof pursuant to C.R.S. 25-7-115.”

<u>Section II.10 – Coal Handling System</u>

- Applied the P002 identified to the table header for the coal handling system.
- Permit conditions were re-numbered due to the removal of conditions for the grandfathered coal crusher.
- Corrected the Regulation No. 3 citations in Conditions 10.1 and 10.2.
- Removed Conditions 10.8.3 (submit written notification of opacity observations required by NSPS Subpart Y) and 10.10.1 (initial performance test for NSPS Subpart Y), since the initial performance test was completed and the results of the test were submitted to the Division.
- Based on comments received during the public comment period, the Division included a requirement to a conduct an annual Method 9 visible emission observation on the cyclone exhaust vent stack.

<u>Section II.11 - Cold Cleaner Solvent Vat</u>

- Added the following note under the table "Note that this emission unit is exempt from the APEN reporting requirements in Regulation No.3, Part A and the construction permit requirements in Regulation No. 3, Part B."

Section II.13 – Particulate Matter Emission Periodic Monitoring Requirements

- Revised the stack testing language in Condition 13.2 to clarify the frequency of testing. The language in the permit addresses testing within the expected five-year permit term. The permit terms may be extended, provided a timely and complete renewal application has been submitted. For the most part, complete and timely renewal applications have been submitted and the term of the permits have been extended beyond the originally anticipated five-year permit term. Therefore, the language has been revised to set specific deadlines for testing, which more appropriately reflects the Division's intent to require testing for particulate matter at a minimum of every five years. To that end, the language regarding waiving testing within the last two years of the permit term, in the event that annual testing was triggered, has been removed. In general, the results of the initial tests have not been above 75% of the standard and annual testing has not been triggered. Therefore, the Division considers that the language is not necessary.

Section II.14 – Continuous Emissions Monitoring System Requirements

- Removed the phrase "and the traceability protocols of Appendix H" from Condition 14.3.2, since Appendix H of the current version of 40 CFR Part 75 is "reserved". Note that Condition 14.3.1 specifies that the continuous emission monitoring systems are subject to the requirements of 40 CFR Part 75 and that would include any applicable appendices, regardless of whether or not they are specifically called out in this condition.

- Replaced the phrase "concerning upset conditions and breakdowns" with "concerning affirmative defense provisions for excess emissions during malfunctions" in Condition 14.5.5 to reflect revisions made to the Division's Common Provisions Regulation.

- The Division had originally intended to remove Condition 14.4.3 (monitoring opacity when the COM is down) from the permit based on citizen comments on another Title V permit. Condition 14.4.3 was not included in the draft renewal permit that went through public comment. However, after further review and based on comments received during the public hearing for this facility, the Division has elected to retain this requirement in the permit.

  Although the coal-fired boiler is subject to continuous opacity monitoring requirements under 40 CFR Part 75, there are periods under Part 75 where monitor downtime is approved, such as period of calibration, quality assurance and monitor repairs, and the Division recognizes that even equipment that is well operated and maintained can experience periods of down time. The alternate opacity language is in addition to the Part 75 monitoring requirements and is intended to provide credible evidence of compliance with the opacity emissions limitations in the permit when the opacity monitor is down.

The alternate opacity monitoring requirements specify three methods that the source may use to assess compliance with the opacity limits when the COMS is down for more than eight consecutive hours. These methods are back-up COMS, EPA Method 9 observations and an "opacity report during monitor unavailability". The back-up COMS and Method 9 observations are straight-forward and are based on the reference method testing. The "opacity report during monitor unavailability" is based on parametric monitoring. The language included in the permit requires that for the "opacity report during monitor unavailability" the permittee record the opacity monitoring reading before and after those periods that the COMS is unavailable. They must also record and maintain a description of operating characteristics that demonstrate the likelihood of compliance including, but not limited to, information related to the operation of the control equipment and any other operating parameters that may affect opacity. Past reports of this nature submitted for other PSCo facilities have noted such items as whether there were operational problems with or corrective maintenance conducted on the baghouse, whether the pressure differential was in the normal range, the unit operating load, and whether there were unit upsets. As previously stated, the "opacity report during monitor unavailability" is intended to provide credible evidence, regarding compliance with the opacity limitations.

In the February 24, 1997 Federal Register, EPA promulgated credible evidence revisions to 40 CFR Parts 51, 52, 60 and 61. EPA states the following in the preamble to this final rule (page 8314, 3rd column):

> The credible evidence revisions are based on EPA's long-standing authority under the Act, and on amplified authority provided by the 1990 CAA Amendments. Section 113(a) of the Act authorizes EPA to bring an administrative, civil or criminal enforcement action "on the basis of any information available to the Administrator." In this provision, which predates the 1990 CAA Amendments, Congress gave EPA clear statutory authority to use any available information--not just data from reference tests or other federally promulgated or approved compliance methods--to prove CAA violations.

In addition, EPA stated that (page 8318, 1st column):

> To the contrary, with regard to sources subject to Title V permits, EPA generally expects that most if not all of the data that EPA would consider as potentially credible evidence of an emission violation at a unit subject to monitoring under the agency's proposed CAM rule would be generated through means of appropriate, well-designed parametric or emission monitoring submitted by the source itself and approved by the permitting

> authority, or through other requirements in the source's permit. Sources not subject to CAM should still be readily able to discern the information, for example information about the operation of pollution control devices, that is relevant to their compliance with applicable regulation.

Finally it should be noted that the alternative opacity monitoring language that is being put back into the Title V renewal permit is in the current Title V permit for this facility and has been in the permit since it's September 1, 2001 initial issuance. The initial Title V permit went through a 30-day public comment period and a 45-day EPA review period prior to issuance.

<u>Section II.17 – Fuel Sampling Requirements</u>

- Since the fuel sampling requirements apply to coal only, the Division revised the title and format of the section. With the revision, there is no Condition 17.1.

<u>Section II.18 – Voluntary Emissions Reduction Agreement – State-only Requirements</u>

Note that the Voluntary Emissions Reduction Agreement is currently a state-only enforceable requirement. However, upon approval of this agreement into the Visibility SIP, these provisions will become both state and federally enforceable.

- Removed the language in parentheses from Condition 18.1.1.3, since the permit clearly identifies B001 (the main boiler) as Unit 5.

- Revised Condition 18.1.2 to replace "upset conditions" with "malfunction".

- Removed Condition 18.1.5 "Startup Problems" since this situation applies to the initial startup of the control technology, not to routine startups of the equipment.

- Revised Condition 18.1.6 to replace "upset conditions" with malfunction" and to remove "startup problems".

- Revised Condition 18.2.1.1 to replace "Upset Conditions" with "Malfunctions" and to remove the remove the references to "Startup Problems".

- Revised Condition 18.2.2 to replace "Upset Condition" with "Malfunctions".

- Based on comments received during the public comment period a statement was added to Condition 18 indicating that the requirements are state-only enforceable until EPA approvals the BART portion of the Regional Haze SIP.

<u>"New" Section II.21 – Regional Haze Requirements</u>

As discussed previously in this document, a construction permit (07BO0110B) was issued on September 12, 2008 to address the regional haze requirements for BART.

The appropriate applicable requirements from this permit have been included in the permit as follows:

- Control technology requirements (condition 1). The Division will include the language in this condition regarding the modification and/or replacement of the NO_X controls. The SO_2 control is already in place and operational and no changes to that technology is required by this permit.

- CEMS requirements (condition 2). The CEMS requirements are already included in the Title V permit.

- NO_X emission limitations (condition 3). This condition will be included in the permit.

- SO_2 emission limitations (condition 4). The SO_2 emission limitations are the already included in the Title V permit.

- PM emission limitations (condition 5). This condition will be included in the permit.

- Compliance schedule (condition 6). This condition will be included in the permit.

- Submittal of Title V permit application (condition 7). Since the conditions of the BART permit are being incorporated into the Title V permit at this time, this condition is no longer relevant and won’t be included in the permit.

- O & M plan requirements (condition 8). The appropriate monitoring requirements will be included in the Title V permit; therefore, this requirement will not be included in the permit.

- Demonstrating compliance with permit conditions (condition 9). The Division considers that the Responsible Official certification submitted in conjunction with the first semi-annual monitoring and permit deviation report submitted after the compliance date for the BART requirements will serve as the compliance demonstration; therefore, this requirement will not be included in the permit.

- General terms and conditions (condition 10). This condition addresses the applicability of general terms and conditions in the construction permit. They are not relevant to the title V permit and will not be include in this permit.

- Reporting requirements (condition 11). This condition will be included in the permit.

<u>Section III – Acid Rain Requirements</u>

- Revised the Designated Representative.

- Revised the table in Section 2 to include calendar years corresponding to the relevant permit term for the renewal.

- Revised the NO_X limit in the table in Section 2. The source had elected to comply with the Phase I NO_X requirements in 1997. Beginning in January, the source was subject to the Phase II NO_X requirements. Therefore, those limits have been included in the permit.

- Removed Section 3, since the NO_X early election expired beginning in January 2008.

- Minor changes were made to the standard requirements (Section 4), based on changes made to 40 CFR Part 72 § 72.9.

- Removed the requirement in Section 5 to submit a copy of any revised certificate of representation to the Division. Submitting a copy of the certificate of representation to the permitting authority is not required under the regulations.

- Removed the requirement to submit the annual reports and compliance certifications in Section 5. As a result of revisions to the Acid Rain Program made with the Clean Air Interstate Rule (final published in the federal register on May 12, 2005), annual compliance certifications are no longer required, beginning in 2006. Note that although the CAIR rule was vacated (July 2008), this revision was unrelated to the CAIR rule and it is expected that these changes will not be affected by the CAIR vacatur. Note that in December 2008, the vacatur of the CAIR rule was over-turned.

Section IV – Permit Shield

- The citation for the permit shield has been revised to reflect revisions and restructuring of Reg 3 and to remove Reg 3, Part C, Section V.C.1.b and C.R.S. § 25-7-111(2)(I) since they don't address the permit shield.

- In Section 3 (Streamlined Conditions) the following changes were made:

  - Corrected the reference to "Section V, Conditions 21.b and c" to "Section V, Conditions 22.b and c".
  - Added the recordkeeping requirements from Reg 1, Section VIII.C, they are being streamlined from the permit in favor of the 5 year Title V recordkeeping requirements in Section V, Conditions 22.b and c, which is noted in Section II, Condition 5.6.
  - Added the appropriate Section of the permit to the conditions that are noted in the first column of the table.

Section V – General Conditions

- Added a version date to the General Conditions.

- The upset requirements in the Common Provisions Regulation (general condition 3.d) were revised December 15, 2006 (effective March 7, 2007) and the revisions were included in the permit. Note that these provisions are state-only enforceable until approved by EPA into Colorado's state implementation plan (SIP).

- Removed the statement in Condition 3.g (affirmative defense provisions) addressing EPA approval and state-only applicability. The EPA has approved the affirmative defense provisions, with one exception and the exception, which is state-only enforceable is identified in Section I, Condition 1.4.

- Replaced the reference to "upset" in Condition 5 (emergency provisions) and 21 (prompt deviation reporting) with "malfunction".

- The title for Condition 6 was changed from "Emission Standards for Asbestos" to "Emission Controls for Asbestos" and in the text the phrase "emission standards for asbestos" was changed to "asbestos control".

- General Condition No. 21 (prompt deviation reporting) was revised to include the definition of prompt in 40 CFR Part 71.

- Replaced the phrase "enhanced monitoring" with "compliance assurance monitoring" in General Condition No. 22.d.

<u>Appendices</u>

- The following changes were made to the insignificant activity list:
    - Removed coal conveying (listed because PM and PM_{10} emissions below 1 tpy), because with the upgrades to the coal handling system, it is no longer an insignificant activity.
    - Removed the exemption category and listing for condensate and crude oil storage tanks, since this exemption category applies to oil and gas condensate and crude oil and likely does not apply to any tanks at this facility.
- Replaced Appendices B and C with the latest versions. In addition added "Unit 5" to the description of the main boiler in the tables to more appropriately identify the unit. Also, the P002 identifier was applied to the coal handling system in the tables. Although this identifier was previously used for the grandfathered crusher, the identifier P003 had been used twice (for the upgraded coal handling system and the recycle ash silos).

- Changed the mailing address for EPA in Appendix D. Removed the Acid Rain addresses in Appendix D, since annual certification is no longer required and submittal of quarterly reports/certifications is done electronically.

PSCo Valmont Total HAP Emissions - Uncontrolled

	HCl	HF	Mercury	Metals	Formaldehyde	Hexane	Acetaldehyde	BTEX	Total
Main Boiler	16.97	83.24	8.30E-03	5.07	0.59	3.41E-03		4.36E-02	105.92
Turbine				1.97	1.77			0.59	4.34
Auxiliary Boiler				2.25E-04	8.05E-03	4.62E-05		5.90E-04	0.01
SWG Turbines					2.09E-00		1.18E-01	7.00E-01	2.91
SWG Heaters				1.04E-04	3.70E-03	8.89E-02		2.72E-04	9.30E-02
Total	16.97	83.24	8.30E-03	7.04	4.47	0.09	0.12	1.34E-00	113.27
Total - SWG Emissions	0.00	0.00	0.00E+00	1.04E-04	2.09	8.89E-02	0.12	7.00E-01	3.00
Total - PSCo Emissions	16.97	83.24	8.30E-03	7.04	2.37	0.00	0.00	6.38E-01	110.27

HAP emission factors for main boiler and auxiliary boiler are based on emissions from worst case fuel.

HCl and HF emissions from the main boiler are based on emission factors used to report actual emissions on APENs for 1997 - 2002 data prior to having the lime spray dryer

PSCo Valmont Total HAP Emissions – Controlled

	HCl	HF	Mercury	Metals	Formaldehyde	Hexane	Acetaldehyde	BTEX	Total
Main Boiler	2.47	3.91	8.30E-03	5.07	0.59	3.41E-03		4.36E-02	12.09
Turbine				1.97	1.77			0.59	4.34
Auxiliary Boiler				2.25E-04	8.05E-03	4.62E-05		5.90E-04	0.01
SWG Turbines					2.09E-00		1.18E-01	7.00E-01	2.91
SWG Heaters				1.04E-04	3.70E-03	8.89E-02		2.72E-04	9.30E-02
Total	2.47	3.91	8.30E-03	7.04	4.47	0.09	0.12	1.34E-00	19.44
Total - SWG Emissions	0.00	0.00	0.00E+00	1.04E-04	2.09	8.89E-02	0.12	7.00E-01	3.00
Total - PSCo Emissions	2.47	3.91	8.30E-03	7.04	2.37	0.00	0.00	6.38E-01	16.44

HAP emission factors for main boiler and auxiliary boiler are based on emissions from worst case fuel.

HCl and HF emissions from the main boiler are based on emission factors used to report actual emissions on APENs for 2004 - 2007 data and take credit for lime spray dryer

PSCo Valmont Actual Emissions (tons/yr)

Unit	PM	PM_{10}	SO_2	NO_X	CO	VOC	HAPS
Main Boiler	44.2	40.7	787.9	2360.7	139.2	17.1	4.26
Turbine	0.1	0.1	0.4	12.8	3.3	0.1	
Aux. Blr*	0.004	0.004	0.001	0.22	0.18	0.012	
Coal - fugitive	5.1	1.3					
Coal - pt source	0.6	0.3					
Ash - fugitive	6.7	2.4					
Ash - pt source (silo)	4	4					
Haul Roads - fug	26	5.5					
Ball mill slakers	0.22	0.22					
Lime storage silos	0.0021	0.0021					
Recycle ash silos	0.02	0.02					
Recycle Mixers	0.02	0.02					
Ash Blower	0.92	0.92					
Total	87.89	55.49	788.30	2,373.72	142.68	17.21	4.26
Total - Fugitive	37.80	9.20	0.00	0.00	0.00	0.00	0.00
Total - Point source	50.09	46.29	788.30	2,373.72	142.68	17.21	4.26

Actual emissions from main boiler, turbine and lime storage silos from APEN submitted 4/30/08 (2007 data)
Actual emissions from aux. boiler, recycle ash silos, ball mill slaker and ash blower based on APEN submitted 4/19/05 (2004 data)
Actual emissions from ash handling, coal handling and haul roads are based on APEN submitted 4/27/04 (2003 data)
HAP emissions from the main boiler are HCl and HF